Public Power Preliminary Responses to BPA's Request for Feedback on 7(b)(2) and ASC Methodology Issues

October 26, 2007

This document contains preliminary responses to the questions asked in BPA's October 10th "Request for Feedback" on the 7(b)(2) Methodology and Average System Cost Methodology. It represents the work of a number of public power representatives, but is not necessarily a definitive statement of the positions any of these representatives will ultimately take on these issues. It is provided as an aid to BPA in developing its initial proposal for its WP-07 Supplemental Rate Case, which BPA has explained it intends to initiate later this year, and it responds to BPA's request that verbal comments made at its October 22nd workshop be submitted in writing.

RESPONSES TO REQUEST FOR FEEDBACK ON 7(B)(2) METHODOLOGY

***Issue # 1*:**

Should the portion of the output of Mid-Columbia hydro resources sold to PNW investor-owned utilities be included in the 7(b)(2)(D) resource stack as available to the BPA to serve 7(b)(2) customer loads?

Response

Yes. The Mid-Columbia hydro output that has been contractually committed to PNW investor-owned utilities should be included in the 7(b)(2) resource stack.

Rationale

For over a decade, BPA has read the language of section 7(b)(2)(D) to require, as a matter of law, that Mid-Columbia resources owned by public utilities that are not dedicated to serving the loads of such public utilities must be treated as being available to serve preference customer load under section 7(b)(2). This has included Mid-Columbia resource output committed under contract to regional investor owned utilities.

This interpretation is consistent with the overall language and intent of section 7(b)(2)(D). This section requires the inclusion in the 7(b)(2) resource stack of ". . . all resources that would have been required, during such five year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers . . . purchased from such customers by the Administrator . . . or not committed to load pursuant to section 839c(b) . . . and were the least expensive resources owned or purchased by public bodies or cooperatives. . . ."

Under section 7(b)(2)(D), the only way that a generating resource owned by a public utility can be excluded from the section 7(b)(2) resource stack is if it has been dedicated to load under section 5(b). This section requires BPA to offer to sell to preference customers federal power equal to that customer's firm load in excess of ". . . the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region." BPA has consistently and correctly interpreted the phrase "such entity" to refer to the preference customer that owns the resource, and has interpreted "not committed to load pursuant to section 839c(b)" to mean not committed to preference customer load.[1] Such interpretation creates a consistent and congruent operation of sections 7(b)(2) and 5(b).

Assuming, *arguendo,* that BPA alters its long-standing interpretation of section 7(b)(2) and 5(b), it must nonetheless read these two sections in a manner that gives meaning to all of their provisions. In particular, if BPA decides that the language ". . . not committed to load pursuant to section 839c(b)" means not just preference customer loads but can include investor owned utility loads as well, it must give full affect to all of the terms of section 5(b) to determine if the preference customer resources have been committed to load pursuant to that section.

In order for an IOU to dedicate a resource to load under section 5(b), a number of specific steps are required. First, the IOU must request a power supply contract from BPA. Second, there must be a determination of the amount of electric power BPA is obliged to provide under such contract by subtracting from the requesting utility's firm power load the ". . . capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region." In short, for there to be a dedication of a resource to an IOU's load under section 5(b), the IOU must have a power contract with BPA under which a net requirement determination, including what resources are dedicated to the utility's load, has been made. Absent these actions, there is not dedication of a resource to load under section 5(b), and the resource must be considered available for the section 7(b)(2) resource stack even if it is under contract to the IOU and the IOU is, in fact, using that output to serve its firm load.

Response to IOU Position

To support their position that the Mid-Columbia resources whose output has been contractually committed to the IOUs cannot be included in the section 7(b)(2) resource stack, the IOUs make the untenable assertion that when a utility sells the output of a generating resource to another party, it no longer "owns" the resource. If such a principle

[1] *See* 7(b)(2) Implementation Methodology, p. 6. ("Three types of resources will be assumed to be available to serve 7(b)(2) customers' loads when the FBS resources are exhausted in the 7(b)(2) case…(2) the resources owned or purchased by 7(b)(2) customers that are not dedicated to *their* own regional loads…"). (Emphasis added). *See also Id*. p. 39.

existed in the law, which surely it does not, many a utility would have been stripped of ownership of generating resources by the act of selling power.

Under the IOU interpretation, the only preference customer owned resources that could be included in the section 7(b)(2) resource stack would be those not used to serve preference customer loads nor sold to other entities. This interpretation cannot be correct. Section 7(b)(2)(D)(i) is limited to resources "purchased by such customers by the Administrator." The IOUs' interpretation would render this provision a null set, since these resources must, by the terms of the Act, have been sold by the preference customer. Thus, "owned" cannot mean that the output of the resource has not been sold. To accept the IOU interpretation would render meaningless the operation of section 7(b)(2)(D). Such an argument does not pass the straight-face test, and provides no basis for overturning a long-standing BPA statutory interpretation.

The IOUs also assert that since the language of section 5(b)(1) makes no distinction between IOU and preference customer load, the statute plainly requires the Mid-Columbia resources sold to the IOUs to be excluded from the section 7(b)(2) resource stack. This argument fails for two reasons.

First, the fundamental purpose of section 7(b)(2) is to determine the cost of serving preference customer load under a specific set of assumptions, including the availability of preference customer owned generating resources to serve their load. In this context, it is both reasonable and consistent with the statute to read the language of section 5(b)(1)(A) as dealing with resources dedicated to serving preference customer loads. And this is precisely how BPA has consistently interpreted this language for over a decade. Even if this were not the case, all the original Mid-C contracts have expired and could no longer be 5(b)(1)(A) resources due to the "loss of contract rights."

Second, assuming *arguendo,* that the IOU assertion regarding the meaning of sections 5(b)(1) and 7(b)(2)(D) have merit, there is no evidence that the IOUs have taken the steps required by section 5(b) to have their contract purchases of preference customer Mid-Columbia resource output considered dedicated to load under section 7(b)(2). In particular, there is no evidence that they have requested and signed a BPA power sales agreement under which their has been a net requirement calculation under section 5(b) that has determined that their Mid-Columbia contract rights are dedicated to load service. And until there is such a demonstration, under the language of section 7(b)(2), the output of the Mid-Columbia resources must be included in the section 7(b)(2) resource stack.

Finally, the IOUs argue that if the preference customer Mid-Columbia resource are included in the section 7(b)(2) resource stack, they must be included at the market cost of power. Once again, the IOU interpretation would render superfluous statutory language.

Section 7(b)(2) provides in part "and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources . . .". If the "least expensive resources owned" by preference customers were priced at market, as suggested by the IOUs, the second clause of this section pricing additional resources at the average cost of all new resources would be rendered surplusage, since the preference customer resources would already be priced at market.

When interpreting a statute, it is axiomatic that all clauses must be given meaning. In this case, in order for the second clause of this section to have meaning, the first clause must be read to require preference customer owned resources to be added to the section 7(b)(2) resource stack at the cost of those resources to the owner, and not what their output might fetch on the market.

Issue # 2

Should the Program Case load forecast for preference customer load be increased for conservation that BPA has purchased since December 5, 1980, the enactment date of the NWPA?

Response

No, the general requirements should be increased, if at all, only as specifically provided for in section 7(b)(2).

Rationale

Section 7(b)(2) itself specifies what adjustments BPA is to make to the "general requirements" of the preference customers. BPA is to assume those general requirements included during the five years under analysis the DSI loads that in fact are then being served by BPA. The term "general requirements" is defined to be "electric power purchased from the Administrator under section 5(b) of this Act, exclusive of any new large single load." Load reductions due to conservation are not part of the general requirements; general requirements are net of conservation induced load reductions. In light of the fact that the Act specifically says how BPA is to assume the general requirements change to ascertain compliance with section 7(b)(2), controlling rules of statutory construction "create[s] a presumption that when a statute designates certain persons, things, or manner of operation, all omissions should be understood as exclusions." *Silvers v. Sony Pictures*, 402 F.3d 881, 885 (9th Cir. *en banc*, 2005) citing *Boudette v. Barnette*, 923 F.2d 754, 756-57 (9th Cir. 1991).

It has been incorrectly claimed that BPA is required to include the cost of conservation in the section 7(b)(2) case because none of the five specified assumptions requires or permits the exclusion of conservation costs from the section 7(b)(2) case. This claim is premised on a fundamental misconception. Section 7(b)(2) does not address the removal of any costs from a program case to arrive at a section 7(b)(2) case. Instead, section 7(b)(2) specifies a load that BPA is to serve (the rate case general requirements of the publics) and a resource stack, and thus the costs implicit in that resource stack, with which BPA is to serve that load. The purpose of section 7(b)(2) is to assure that the resource costs, exclusive of conservation and experimental resources, in the rate charged the publics not exceed the resource costs specified in section 7(b)(2). Conservation costs are, by the express terms of section 7(b)(2), not within the costs from which preference customers are protected, and are to be paid in full regardless of whether the resource costs in the section (7)(b)(1) resource stack or the section 7(b)(2) resource stack are higher. The notion that the publics are to pay twice for conservation, once as part of the 7(g) costs excluded from the section 7(b)(2) test, and once as part of the section 7(b)(2) costs is an impermissible interpretation that has no basis in the Act.

Issue #3

Should section 7(b)(2)(E) reserve benefits be limited to reserves provided by Direct Service Industry (DSI) loads?

Response

Yes, because the reserves provided by DSI loads under section 5(d) of the Northwest Power Act are the only reserves that qualify for consideration under section 7(b)(2)(E). By no means do surplus sales made by BPA provide any statutory reserves, nor do they provide "quantifiable monetary savings" that could be considered in section 7(b)(2)(E).

Rationale

It has been suggested that surplus power sales by BPA provide reserves, and that those reserves have a value that should be considered in the context of section 7(b)(2)(E) of the Northwest Power Act. For at least three reasons, this is incorrect.

<u>Surplus Sales Contracts Do Not Meet The Definition Of Reserves</u>

The Northwest Power Act defines "reserves" as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers . . . and available to the Administrator . . . from *rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers*." (Northwest Power Act, § 3(17)). Contract provisions that existed in the DSI contracts fit this definition because they represented a specific right to curtail power deliveries under those contracts in order to operationally benefit the system and allow the Administrator to meet his load-serving obligations. In contrast, BPA surplus sales are not accompanied by any right for BPA to interrupt, curtail or otherwise withdraw portions of the electric power provided to such purchasers under the sales agreements. These sales simply terminate at some point in time. Because a power contract does not provide for power deliveries after its term, a contract termination is not reasonably characterized as right to "interrupt, curtail or otherwise withdraw" any of the "portions of the electric power supplied to customers" under the contract.

Section 7(b)(2)(E) Limits Reserves That Are To Be Considered To Those Achieved Because Of The Northwest Power Act

Even if surplus power sales by BPA qualified as "reserves" under the Northwest Power Act, they could not be considered in the context of section 7(b)(2)(E). Section 7(b)(2)(E) does not allow for consideration of all reserves—it allows consideration of "reserve benefits [achieved] *as a result of the Administrator's actions under this chapter* [(the Northwest Power Act)]." (emphasis added). Any "reserves" that are created in conjunction with the Administrator's sale of surplus power are not reserves that are achieved as a result of the Administrator's actions under the Northwest Power Act. Any such "reserves" were achievable under the Bonneville Project Act, which allows the Administrator to dispose of power surplus to preference customers' needs, and gives authority to include curtailment, interruption, or withdrawal rights in such contracts. (*See* Bonneville Project Act, §§ 2(a), 2(f), 4(b), 5(a)). In contrast, the reserve benefits realized from the DSI contracts were achieved because of the specific provisions of the Northwest Power Act that mandated DSI service during the initial contract period, so long as curtailment rights were provided in those contracts. (Northwest Power Act, § 5(d)(1)(A)).

BPA has recognized that reserves must be achievable because of provisions of the Northwest Power Act in order to be considered in the section 7(b)(2) analysis. In its 1984 7(b)(2) Implementation Methodology, BPA stated that the reference point for quantifying the savings associated with reserves under section 7(b)(2) is "what the costs of the reserves would have been if BPA had not been able to take the actions authorized by the Northwest Power Act." (7(b)(2) Implementation Methodology, p. 8). Without the Northwest Power Act, BPA could not have supplied power to the DSIs in contravention of public preference. In contrast, it could sell surplus power.

Surplus Sales Do Not Provide Reserves With Quantifiable Monetary Savings

For an additional reason, even if surplus power sales created "reserves," BPA could not consider those reserves for purposes of section 7(b)(2)(E) since there would be no "quantifiable monetary savings" resulting from them. The Northwest Power Act directs BPA to add to its 7(b)(2) calculation the "quantifiable monetary savings" associated with reserves achieved under the statute. Reserves have a "quantifiable monetary savings" to be recognized in section 7(b)(2) only to the extent that the cost to BPA of the contract rights is less than the alternative means of acquiring reserves.

With respect to the reserves provided by the DSI contracts under the Act, the Act contemplated a value accruing from those reserves that could differ from the amount of credit that was provided to the DSIs for providing those reserves. The "monetary savings" were the value of the interruption rights in excess of the adjustment made to the DSI rate. Surplus sales, on the other hand, are negotiated, market-based sales. Any value to BPA to interrupt deliveries under such sales, even if such rights did in fact exist, would reduce the market price of such sales by the value of the rights, and BPA would have no savings. There is no "quantifiable monetary savings" from the right to buy reserves for exactly what the reserves are worth.

Certainly, the revenues from surplus sales are not a measure of the monetary value of any reserve rights that might be associated with such sales, just as the revenue from interruptible sales to the DSIs were never considered to constitute the quantifiable monetary savings resulting from the interruption rights contained in those contracts.

Issue #4

What direct service industrial ("DSI") loads should Bonneville Power Administration ("BPA") consider in application of section 7(b)(2)(A)?

Response

BPA should continue to consider in the section 7(b)(2) test only the DSI loads that BPA expects to directly serve during the rate test period, and not the DSI loads that BPA served at the time the Northwest Power Act passed.

Rationale

Under the Northwest Power Act, BPA must create a hypothetical cost of power based on its actual power rates, modified by the five assumptions listed in section 7(b)(2) (the "7(b)(2) Case Rate").

Under section 7(b)(2)(A), BPA is to assume that the publics serve with BPA power those DSI loads that are within or adjacent to the publics. A question has been raised about whether past DSI loads should be included. It has been argued that the distinction in tense between "had included" and "are served" means the DSI loads are those that "are served" at the time of the enactment of section 7(b)(2).

Such an interpretation ignores the plain language of the statute which specifically states that BPA must assume that the publics had served those DSI loads "which are served by the Administrator . . . ." The use of the word "are" requires BPA to consider those actual DSI loads which the Administrator serves and not hypothetical or past DSI loads. When Congress uses the present tense in a statute it applies to both present and future actions, not to past actions. *United States v. Jackson*, 480 F.3d 1014, 1019 (9th Cir. 2007).

If Congress had meant to base BPA's 7(b)(2) calculation on those DSI loads that were served at the time the statute was passed, then it would have stated so. In numerous other provisions in the Northwest Power Act, Congress limited certain requirements to the time the law was passed or other specific dates. For example, in section 7(b)(2) Congress distinguishes between power sales immediately after the Northwest Power Act passed and those made after July 1, 1985. 16 U.S.C. § 839e(b)(2) Similarly, the new large single load provisions apply to new loads served after September 1, 1979. 16

U.S.C. § 839a(13)(A). Congress also considered specific time periods in calculating the 7(b)(2) Case itself when Congress referred to "contracts existing as of December 5, 1980 . . . ." 16 U.S.C. § 839e(b)(2)(B). Therefore, Congress clearly knew how to limit a particular provision to the time the statute was passed, and Congress' failure to do so means Congress decided not to do so for the DSI loads in the 7(b)(2) Case.

Issue # 5

Should BPA consider natural consequences in the rate test? Should additional or expanded natural consequences be considered? Are the current natural consequences implemented appropriately?

Response

Only the inevitable consequences of the assumptions specified in section 7(b)(2) may be considered in section 7(b)(2). BPA may not expand those statutorily defined assumptions by labeling additional assumptions as "natural consequences."

Rationale

If by natural consequences BPA means the inevitable result of a statutorily specified assumption, then BPA is required to reflect such consequences in the section 7(b)(2) test, as that is the very reason the NWPA requires BPA to adopt the assumption. Thus, if as a result of assuming that the within and adjacent DSI load is part of the general requirements, such general requirements thereby increase, and such general requirements are served solely with FBS resources, then BPA must assume less FBS is available to sell as surplus power. However, BPA is told exactly how to adjust the general requirements, and BPA cannot make additional adjustments under the guise of accounting for "elasticity"; nor can it assume that the DSI load served by BPA is other than such DSI load once it is included in the general requirements of the preference customers. It is simply not inevitable that a known DSI load is larger than it is.

Issue # 6

Over what period should the rate test be considered?

Response

The Northwest Power Act requires that the period over which the rate test should be considered is any year for which rates are being set, plus the ensuing four years. That means, if BPA has a rate period longer than one year, it must look at the rate during each year of the rate period and the four years thereafter.

Rationale

The section 7(b)(2) consideration period is explicitly set out in the Northwest Power Act—for any year that BPA sets rates, it must look to such year plus the ensuing four years.

BPA states that "[a]n issue has been raised whether the rate test should be limited to the first year of the rate period plus the ensuing 4 years without respect to the length of the rate period." Doing so would not comport with the language of section 7(b)(2), which establishes the proper period as "any year after July 1, 1985, plus the ensuing four years." If, for example, BPA were to limit the rate test period to the first year of a rate period, plus the ensuing four years when it sets rates for a two-year period, it would be violating section 7(b)(2) with regard to the rate it would be setting for the second year of the rate period. This is because the "projected amounts to be charged" preference customers during that second year would not be measured under the rate test for that year plus the ensuing four years as required by the Act. Instead, BPA would be setting those amounts to be charged preference customers based on a determination of the rate test for that year plus the ensuing three years.

If BPA were to look at the two year rate period plus four more years, then BPA would be looking at the year plus five years for the first year of the rate period. In short, section 7(b)(2) requires the rate test consideration period to extend four years beyond each year for which it is setting rates. If BPA sets rates for a period longer than one year, the rate test must be met for each year of the rate period plus the four years following each such year.

Issue #7

Should BPA reconsider the 7(g) costs that reduce the Program Case rate?

Response

No. Section 7(b)(2) explicitly states which 7(g) costs are outside of the rate protection provided to preference customers.

Rationale

The specific 7(g) costs for which section 7(b)(2) provides no rate protection are listed in the NWPA, and BPA cannot lawfully add to that list. The so-called uncontrollable events raised by the IOUs in past rate cases are either defined by the NWPA as FBS costs (the uncompleted nuclear plants) or are BPA judgments on the amount of financial cushion BPA chooses to include in its rates due to BPA's risk aversion. Conscious choices made by BPA cannot be reasonably characterized as uncontrollable events.

Even if BPA's PNRR could be characterized as an uncontrollable event, such costs could not be included in the §7(b)(2) case, because as such they could not be treated as resource costs. One does not "remove costs" from the program case to arrive at the section 7(b)(2) rate limit. BPA is directed to assume it is serving certain loads with certain resources (and their associated costs, which is the inevitable consequences of using a resource to serve a load). The costs that go into the section 7(b)(2) case are those specific resource costs. Section 7(b)(2) does not direct BPA to assume that certain unspecified uncontrollable events occur in the section 7(b)(2) world to drive up costs over and above the cost of serving the specified load with the specified resources.

Issue # 8

Should the individual annual Program Case and §7(b)(2) Case rates be converted to constant dollars before averaging for comparison?

Response

In its RAM computations today, BPA calculates rates for each year of the rate period plus the subsequent four years for both the Program (including the section 7(g) adjustment) and 7(b)(2) cases. It then discounts both results back to the present—actually, the year prior to the present—which becomes the protection to be provided to preference customers and, monetized using preference customer loads, to be added as section 7(b)(3) charges. The discounting is done with "nominal" discount rates, and "real" rates and differences are the result.

The suggestion, apparently, is to discount the nominal BPA rates to real rates, and then discount them again. One could do so, but the final discounting would have to be done with "real" discount rates—that is, stripped of inflation.

Double discounting only with nominal rates is a serious economics error. Using real discount rates correctly for the second step will produce the identical result as BPA has calculated.

Issue #9

Should residual costs of additions from the 7(b)(2)(D) resource stack from prior rate cases be recognized in subsequent rate tests?

Response

No. It is inappropriate for residual costs of additions from the 7(b)(2)(D) resource stack from prior rate cases be recognized in subsequent rate tests – the rate test model should be run afresh in each rate case.

Rationale

The NWPA is very explicit about the resources that are to be used in the section 7(b)(2) rate test. They are the resources needed to serve the general requirements of the preference customers if those general requirements had included the loads of the within and adjacent DSI then served by BPA. There is no instruction to add in resources that may have been appropriate for use in a prior case for which both the general requirements and the loads of the within and adjacent DSIs may have been dramatically different, and the available resources may have been dramatically different as well.

Issue # 10

If BPA continues to provide financial payments to DSI customers in lieu of power, should those payments be subtracted from the 7(b)(2) Case revenue requirement?

Response

Including the cost of those payments in the 7(b)(2) case is not appropriate under the statute.

Rationale

The analysis required by section 7(b)(2) is not merely the program case, minus certain specified elements. In contrast, it is a case that must be modeled under the specific assumptions listed in section 7(b)(2). Section 7(b)(2) requires a construction of what the power costs to serve the general requirements of publics' load would be, given the specific assumptions listed. Financial payments to the DSIs do not qualify as a power cost of serving the general requirements load of the publics under the assumptions outlined in 7(b)(2), and cannot be included in that calculation.

Issue # 11

If a DSI is served through a surplus sale to an adjacent preference customer, should the load be treated as a surplus load or a DSI load?

Response

A DSI taking service under a contract with a public utility that purchases surplus power from BPA is not a DSI as defined by the statute, and cannot be included in the within or adjacent to DSI load category under section 7(b)(2).

Rationale

The Regional Act defines a DSI as ", , , an industrial customer that contracts for the purchase of power from the Administrator for direct consumption." In the case where a former DSI has elected to sign a contract with a public utility for its power supply, rather than with BPA, it no longer falls within the definition of a DSI under the Regional Act. The absence of a contract with the Administrator for power ensures that result.

Under section 7(b)(2), an industrial concern that formerly had a direct contract with BPA for power supply for direct consumption that elects to contract with a public utility for its power supply is not a DSI as defined in the Regional Act. As a consequence, the load of such industrial customer cannot be treated as a within or adjacent to DSI load under section 7(b)(2).

Issue # 12

The rate test considers Federal Base System power used for Program Case firm surplus sales as available to serve 7(b)(2) customer loads. How should the rate test treat requirements sales to preference customer load if that sale is made at a 7(f) rate?

Response

Sales of surplus power to preference customers are not sales to serve the general requirements of such customers, and hence cannot be considered a preference customer load under section 7(b)(2).

Rationale

The only preference customer loads that can be included under section 7(b)(2) are the "... general requirements of the public body, cooperative and Federal agency customers... ". General requirements are defined under section 7(b)(4) as meaning "... the public body, cooperative and Federal agency customer's electric power purchased from the Administrator under section 839c(b) of this title ... ". The power that public bodies, cooperatives and Federal agency customers are entitled to purchase from BPA is sold to them under rates established in accordance with Section 7(b), which provides in part:

> "The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative and Federal agency customers. . ."

The operation of these three sections of the Act mean that the term "general requirements" is limited to power which such customers are entitled to purchase from BPA under section 5(b) under rates established under section 7(b).. As a consequence, the term "general requirements" excludes surplus sales for which no purchase right is established under section 5(b), and which is sold under rates established under section 7(f). The Act prohibits the inclusion in the 7(b)(2) loads preference customer loads served with surplus power under section 7(f) rates.

Further, for purposes of establishing the section 7(b)(2) resource stack, Federal base system resources used to make firm surplus sales must be considered available to serve section 7(b)(2) preference loads. This conclusion is required by the plain language of section 7(b)(2), which provides in part "public body, cooperative, and Federal agency customers were served . . . with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980 . . .". Since these surplus sales were not in place as of that date, they must be considered available to serve the general requirements of preference customers under section 7(b)(2).

Issue # 13

Should the treatment of Type 1 and Type 2 resources be modified?

Response

Yes. Both Type 1 resources should be added to the resource stack in the amount of the purchase actually made from the customer, while Type 2 resources should be added in amounts only as needed to serve the 7(b)(2) loads, rather than in large lumps.

Rationale

Type 1 resources are those acquired by BPA from the customers. Since these acquisitions are made in discrete amounts fixed by the term of the contract, as was the case in the acquisitions of Cowlitz Falls and Idaho Falls, there is little basis for adding these resources to the 7(b)(2) resource stack in any quantity other than the amounts actually acquired by BPA.

A different result pertains to Type 2 resources. Since Type 2 resources are deemed available to serve 7(b)(2) loads as a result of the comparison under the 7(b)(2) construct, these resources may be added to the 7(b)(2) resource stack in amounts equal to the amount of such resource projected to be needed to serve 7(b)(2) loads. This approach is supported by the fact that since the passage of the Regional Act, a liquid and accessible wholesale power market has developed in the Western Interconnection, including the Pacific Northwest. It is reasonable to assume that Type 2 resources not dedicated to load would be otherwise sold on this newly developed market. This makes it possible for BPA to acquire power from Type 2 resources in amounts equal to that forecast to be needed to serve 7(b)(2) load. This is a reasonable approach to the use of Type 2 resources, and there is no language in the Regional Act that requires BPA to employ a different approach.

Issue #14

Should the 7(b)(3) allocation of the rate protection amount be modified to include an allocation to surplus sales?

Response

No, the allocation of any portion of the section 7(b)(3) surcharge amounts to market based rates would have the affect of indirectly charging such surcharge amounts to the preference customers, in violation of section 7(b)(2) and (3).

Rationale

Section 7(b)(3) provides in part "Any amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all *customers."* BPA inquires whether this language either permits or requires BPA to allocate any section 7(b)(3) surcharge amount to market based power sales.

The answer to this question is no. Section 7(b)(3) speaks specifically to power sales to "customers". The term "customer" is defined in the Act as ". . . anyone who contracts for the purchase of power from the Administrator pursuant to this chapter." *See* 16 U.S.C. § 839a(7). The Act specifies in a number of places who is a customer by virtue of contracting with BPA for the purchase of power. Perhaps the clearest articulation of who qualifies as a customer under the Act is set out at section 5(g)(1)(A), (B) and (C). This section obligates BPA to offer contracts for the sale of power to public bodies and cooperatives, Federal agencies, electric utilities and direct service industrial customers. Based on the definition of customer, it is the rates for the sale of power to these customers, other than preference and cooperative customers, to which section 7(b)(3) surcharges must apply.

This conclusion is reinforced by the fact that when the Act does make reference to sales of surplus or market power, it does so without making any mention of contracts, which is the crucial element necessary to qualify a power purchaser as a "customer". See, section 839c(f). Read together, these sections of the Act not only do not permit, but in fact expressly prohibit, the allocation of section 7(b)(3) surcharge amounts to market sales.

There is a second and even more compelling reason why section 7(b)(3) surcharges cannot be assessed to market based sales. The purpose of a section 7(b)(3) surcharge is to collect from other customers the amounts not charged to preference customers due to the operation of section 7(b)(2) to ensure BPA covers its costs, as required by section 7(a). The allocation of any portion of a section 7(b)(3) surcharge to market rates would not collect additional revenues, and hence would not ensure that BPA would cover its costs.

Further, such an allocation would actually result in preference customers being charged, through a reduction in their non-firm revenue credit, the costs of the rate protection that section 7(b)(2) is supposed to provide to them. Simply stated, allocating the section 7(b)(3) surcharge to market rates would deprive preference customers of the cost protection they are supposed to receive under section 7(b)(2).

It is axiomatic that BPA cannot, consistent with the law, interpret one section of the Act (section 7(b)(3)) in a manner that defeats the purpose to be achieved under another section on the Act (section 78(b)(2)). BPA made this identical legal error in the last two rate cases by interpreting its settlement authority as permitting it to override the costs protection provided preference customers by section 7(b)(2). The 9th Circuit has made it clear in three opinions that BPA interpretations of the Act that have the result of depriving preference customers of their section 7(b)(2) cost protection will not stand. Allocating section 7(b)(3) surcharges to market rates would deprive preference customers of their section 7(b)(2) cost protection, and upon examination by the 9th Circuit would not be permitted to stand.

Issue # 15

Should the implementation methodology deal with how REP settlements are treated in the rate test?

Response

Yes, the implementation methodology should expressly deal with the treatment of settlements. It should do so by treating the costs of settling BPA's REP obligations as an REP cost in the program case. Further, BPA should ensure that any REP settlement agreement expressly permits BPA to alter the level of settlement benefits if required to comply with the results of the operation of the 7(b)(2) rate ceiling for a rate period.

Rationale

One of the most basic of the holdings in *Golden Northwest* was that the costs of settling the REP obligations are indeed costs of the REP. As a consequence, such REP settlement costs must be included in the costs of the REP that are reflected in the program case for purposes of performing the 7(b)(2) rate ceiling, and the implementation methodology should reflect this.

There is an implication from this holding from *Golden Northwest* that should also be considered in structuring such REP settlements. Since the rate ceiling sets the limit that BPA may charge preference customers to fund the REP, including REP settlements, any such settlement must permit BPA to adjust the level of benefits downward if such reduction is necessary in order to bring the level of REP benefits (including benefits under settlement) into line with the benefit level established for a rate period by the rate ceiling. Failure to include such a provision in future REP settlements will result in REP benefits exceeding the limits established by the rate ceiling.

Publics' Response to New Question Raised by IOUs (#16 on IOUs' Response)

Should the net requirements of any utility be decreased to the extent it both purchases power at Tier 1 rates and participates in the REP?

Response

There should be no reduction to the net requirements of a public utility that participates in the REP.

Rationale

The right of a preference customer to purchase power from BPA is established by statute. See, section 5(b). Further, the right of a preference customer to participate in the REP is established by statute. See, section 5(c). There is simply no statutory basis, and the IOUs have cited none, for the proposition that the exercise of one statutory right can be conditioned on the surrender or reduction of another statutory right. This appears to be nothing more than an attempt to deprive preference customers of the rights granted to them by law under the Regional Act.

Publics' Additional Issue #1

How should the in lieu provision be structured for purposes of the implementation of section 7(b)(2) and the RPSA?

Response

The in lieu provision should be structured in a manner that provides BPA with a reasonable opportunity to control the costs of the REP, while providing the IOUs with adequate advance notice of any in lieu transactions in order to incorporate them into their financial planning.

Rationale

The Act provides that ". . . in lieu of purchasing any amount of electric power offered by a utility under paragraph (1) of this subsection, the Administrator may acquire an equivalent amount of electric power from other sources to replace power sold to such utility as part of an exchange sales if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility." 16 U.S.C. § 839c(c)(5). This section serves as a cost control mechanism by permitting BPA to substitute the cost of power available to BPA for the ASC of an exchanging utility.

This provision should be implemented in both 7(b)(2) and the REP contract in a manner consistent with forecast and rate period approach being used by BPA. First, implementation of the in lieu provision should be a strictly financial transaction, and should be based on the cost of power BPA forecasts being available on the market that it uses in the relevant rate case for all purposes. In this construct, there would only be a substitution of the in lieu price for the utility ASC and no delivery of in lieu power to the exchanging utility. And since BPA sells its surplus on the market, BPA surplus power should be considered available for any in lieu transactions without the need to make an additional power purchase.

Second, the notice of in lieu provisions should be coordinated with the BPA determination of ASCs and the commencement of the rate process. In particular, BPA should give notice of its intention to engage in an in lieu transaction concurrently with its final determination of the utility ASC. The notice should be for all periods during the upcoming rate period during which in lieu transactions will be in effect, and the minimum period for which an in lieu transaction can be made should be one calendar quarter.

This approach would give the utility adequate notice of the pending in lieu transactions, and would base the transaction on the BPA market price forecast used in the rate case. It would also allow BPA to incorporate into the implementation of the section 7(b)(2) rate ceiling any noticed in lieu transactions.

Publics' Additional Issue #2

What should BPA do with debit balances in deemer accounts?

Response

Debit balances in deemer accounts should roll forward with interest; any future residential exchange benefits that may be owed an exchanging utility should be netted against debit balances until the balance has been fully extinguished. Future benefit payments (credits) will be available to utilities at that time.

Rationale

Section 5(c)(1) provides that "whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region." 16 U.S.C. § 839c(c)(1).

This section sets up a formula that is mathematically neutral in the sense that it does not compel the payment of benefits. The statute applied according to its terms could result in BPA providing lower cost power to the utility or the utility providing lower cost power to BPA. In other words, the utility may receive benefits, or the utility may pay. The "deemer account" was and is a way of mitigating the effect on low-ASC utilities of making payments to BPA by permitting them to carry debit balances until they can be offset in the future with actual benefits.

For those utilities that entered into residential purchase and sale agreements with BPA, either in 1981 or 2001, and currently have debit balances in their deemer accounts, the only options available under the statute are for those balances to be paid or rolled forward with the expectation that balances will be offset in the future with any positive benefits to which the utility may be entitled. As rolling the balances forward is consistent with past practice and least disruptive to the involved utilities, public power recommends this approach.

RESPONSES TO REQUEST FOR FEEDBACK ON AVERAGE SYSTEM COST METHODOLOGY

Issue # 1

What construct should BPA use to determine a utility's ASC.

Response

Public power produced a separate document responding to this issue, which has already been reviewed by workshop participants and BPA.

Issue # 2

Should return on equity be included as a resource cost?

Response

No. Return on equity should not be included because it is not a resource cost.

Rationale

The legislative history of the NWPA stressed the goal to reduce the difference in wholesale power cost of IOUs and publics served by BPA caused by the IOUs having been forced off the BPA system in 1973 and their consequent need to acquire newer vintage resources at higher nominal costs. This same history makes clear that any cost differences between BPA and the IOUs before this time was *de-minimis*. This suggests strongly that it was the difference in cost caused by the average vintage of BPA and IOU resources, and thus, the nominal dollars invested in those resources, that the residential exchange was designed to address. The higher cost created by risk associated with the IOU corporate structure (the need for equity in the capital structure due to not being self regulated, and the taxable nature of their interest payments) was not something the NWPA intended to shift to other parties. "The IOUs incorrectly assume that the costs of equity in excess of the cost of debt, i.e. the risks of the business enterprise, are resource costs within the limits of section 5(c)(7)." BPA's 1984 ASC Methodology ROD, p 53.

Moreover, one clear benefit the NWPA made available to all IOUs was the potential financing benefits associated with BPA's newly acquired purchase authority. It was anticipated that resource backed by an output sale to BPA at prices that guaranteed resource cost recovery to the IOU could be financed with 100% debt at relatively low interest rates. If the IOUs had taken advantage of this option, and then bought the power back from BPA at a cost based rate under section 7(f), the IOUs' current resource costs could be much lower than they are. However, the IOUs earn nothing for their shareholders by financing resources solely with debt. Therefore they chose not to take advantage of the financing cost savings made available by the NWPA and continue to rely on equity financing for the sole benefit of their shareholders, thus driving up their costs to their customers with no offsetting benefits.

For both these reasons, equity returns should not be treated as part of the average system costs of resources. Returns on equity are a function of the structure of a utility and its enterprise risks, not a cost of resources, and their purpose is to provide profits to shareholder to compensate them for bearing the enterprise risks. Although BPA may have been motivated in 1984 to remove equity returns from ASC by the terminated plant cost issue, BPA concluded that equity returns are not part of ASC within the meaning of 5(c). In addition, the issue of terminated plants remains a concern because of regulatory changes regarding renewable portfolio standards and carbon regulation that could result in new terminated plant costs.

Issue # 3

Should income and revenue related taxes be considered resource costs?

Response

No. Income and revenue related taxes are not resource costs.

Rationale

Just as equity returns are not a cost of resources, the income taxes payable on those equity returns are not a cost of resources. As BPA succinctly put it in its 1984 ASC Methodology ROD:

> Earning a profit and the resultant income tax liability is one of the primary differences between the publicly owned and investor-owned utilities. This basic difference should not be affected by the residential exchange. Income taxes are a function of the nature of an enterprise as an investor-owned utility. The tax laws make investor-owned utilities revenue collectors for the government. Income taxes are not resource costs. Publicly-owned utilities own the same types of power resources, yet incur no tax expense.
>
> Subsidization of income taxes serves to confer on investor-owned utilities the tax advantages of publicly owned utilities. This extra benefit goes far beyond the purpose of the residential exchange intended by Congress. The exchange should not be a vehicle for redistributing tax burdens from exchanging utilities to BPA's other customers (including publicly owned preference customers) or to the

> Federal Treasury (to the extent BPA rates fail to recover the full cost of the residential exchange subsidy)."

BPA's 1984 ASC Methodology Record of Decision, p 60-1; *affirmed PacifiCorp v. FERC*, 795 F.2d 816, 822-23 (9th Cir. 1986).

For the same reasons, BPA also ruled that revenue taxes were not resource costs and that they should be excluded from ASC. *Id*. 62

Issue # 4

Should transmission costs be considered resource costs?

Response

Transmission costs should only be included as resource costs to the extent they are appropriately functionalized as a generation cost.

Rationale

As part of calculating the benefits to which an exchanging utility is entitled under the Residential Exchange Program, BPA compares that utility's average system cost of resources to the PF exchange rate, which is based on the PF rate, plus any 7(b)(3) allocation amounts.

In the past, BPA's PF rate included transmission costs, so including the IOUs' transmission costs in their ASC may have made sense. Now, however, including transmission costs as resource costs of an exchanging utility would provide an improper comparison between the PF rate (which does not include transmission) and an exchanging utility's costs of transmission plus resource costs.

BPA's current PF rate includes only the transmission costs that FERC will not allow to be recovered in transmission rates. BPA should only include transmission costs of an exchanging utility that FERC requires the utility to exclude from its transmission rate.

Publics' Additional Issue #1

How should a utility's conservation costs be treated in the ASC Methodology?

Response

BPA should adhere to its original determinations in its 1984 ASC Methodology and ROD in order to determine how to treat conservation costs, with few exceptions. Regarding Oregon IOU payments to the Energy Trust, BPA should not allow those costs as conservation/resource costs.

Rationale

In its 1984 Average System Cost Record of Decision (ROD), BPA addressed the appropriate treatment of conservation with regard to ASC determinations. *See* ROD, pp. 69-74. Except where noted in the description below, that approach is still generally relevant to the determination of conservation costs for ASC purposes moving forward.

- BPA has the statutory authority to ensure that impermissible conservation costs are not allowed in ASC. *See* ROD, p. 72.

- Conservation A&G expenses should be limited to only those expenses relating to conservation measures for which power is saved by physical improvements or devices. ROD p. 74. Conservation costs are costs of measures or resources for which power is (or is planned to be) saved by means of physical improvements, alterations, devices, or other installations which are measurable in units. ASC Methodology, p. 19.

- Only conservation costs funded by the utility will be functionalized to production in the utility's average system cost. Methodology, p. 19.

- Conservation costs must be incurred as part of a program that is consistent in terms of cost and timing with the conservation plan developed by the Council in order for these costs to be exchangeable. That is, if a utility pursues conservation that is in excess of the Council's plan, the utility's customers should pay for this, not BPA's customers. ROD pp. 69, 73. Conservation and associated costs must be generally consistent with the Regional Council's resource plan as determined by the Administrator. Methodology, p. 19.

- In the August 21 BPA ASC handout, page 36, BPA erroneously said, "The exchanging utility may only exchange Model Conservation Standards that are mandated by Section 4(f)(1) of the Northwest Power Act." This is at odds with the 1984 ROD that states: "In implementing the (model conservation) standards the utility is not actively pursuing resources, but merely ensuring that the model conservation standards are met. Therefore, model conservation standards are not resource costs". Also, in the 1984 ROD BPA found that disallowing model standards costs from ASC does not discourage utilities from implementing the Council's plan. This lead BPA to disallow model conservation standards cost from ASC. Also, mandated surcharges are not exchangeable. ROD, p. 73. *See also*, Methodology p. 19. Costs required by a government entity through building code provisions or programmatic costs in lieu of building code provisions are not exchangeable.

- Conservation costs incurred to promote changes in consumer behavior are not exchangeable. Methodology, page 19. Advertising, promotion, pamphlets, leaflets, brochures and audit expense are not resource costs and are therefore not includable in ASC. ROD, p. 74; Methodology, p.19.

As discussed above, the cost of complying with Model Conservation Standards is not exchangeable. In Oregon the investor owned utilities charge their retail customers a public purpose charge of 3%. Some of the funds derived from this charge are sent to the Oregon Energy Trust for energy efficiency and renewable energy projects. The balance is distributed to schools and to community action agencies for low income weatherization, low income housing and low income bill payment assistance. In 2006 PacifiCorp and Portland General Electric sent $50 million in total to the Trust. The Trust in turn uses these funds to provide incentives for residential, commercial and industrial customers to implement measures that will conserve energy at their homes or facilities.

The Northwest Power and Conservation Council has indicated that one of the primary ways that a utility can meet the model conservation standards is to provide funding to the Energy Trust. Many of these measures are Energy Star devices or measures. The Trust in turn uses these funds to provide incentives for adopting Energy Star devices and measures. Therefore, since the payments to the Energy Trust are related to complying with model conservation standards, they need to be evaluated to remove these payments in the calculation of the ASC for these utilities. *See* p. F-3 http://www.nwcouncil.org/energy/powerplan/plan/Appendix%20F%20(Model%20Conservation%20Standards).pdf. Other IOUs in the region pay for the cost of complying with model conservation standards. These costs are non-exchangeable. Similar treatment should be given to those Oregon utilities that meet their model conservation requirements through payments to the Energy Trust.

Additionally, payments to the Energy Trust are simply collected from consumers by Oregon IOUs, and passed through to the Trust, putting the IOU more in a position of a tax collector than an active participant in pursuing or funding conservation measures. As described in the third bullet above, only conservation costs *funded by the utility* are functionalized to production under the current ASC Methodology. Because Energy Trust funds are collected and passed along, the funds are not "funded by the utility" and therefore should not be credited to a utility's resource costs in BPA's ASC Methodology. Methodology, p. 19